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Review of SO2 Control Alternatives for Colstrip Units No. 3 and No. 4

Pacific Environmental Services, Inc.
Santa Monica, CA

Prepared for

Environmental Protection Agency
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REVIEW OF SO_2 CONTROL ALTERNATIVES

FOR COLSTRIP UNITS #3 AND #4

J. C. Serne - Project Manager

January 1978

Prepared for the:

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16. ABSTRACT

Montana Power Company is planning construction of two additional coal-fired electric generating units at its facility at Colstrip, Montana. Colstrip Units #3 and #4 will be equipped with scrubbers to remove particulates and sulfur dioxide, as required to meet New Source Performance Standards (NSPS) and Class I Prevention of Significant Deterioration (PSD) regulations. The objective of this study is to evaluate the SO2 control alternatives for Units #3 and #4. The design and performance of the scrubbers serving Units #1 and #2 are described. Sulfur dioxide emission rates from Units #3 and #4 are predicted, assuming a similar scrubber design and performance as reported for the existing units. Potential modifications to the planned scrubber design which might be expected to improve SO2 collection efficiencies are described. A brief summary of alternative SO2 control systems potentially available for Colstrip Units #3 and #4 is presented along with cost performance information and associated environmental and engineering sacrifices.

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1.0 INTRODUCTION

The Montana Power Company currently operates two 360 MW (gross) coal-fired electric generating units at Colstrip, Montana. These existing units, #1 and #2, are equipped with scrubbers designed to remove both particulates and sulfur dioxide from the flue gas. Montana Power Company is planning construction of Units #3 and #4 at Colstrip, each with a 700 MW capacity. Colstrip Units #3 and #4 will be equipped with scrubbers to remove particulates and sulfur dioxide, as required to meet New Source Performance Standards (NSPS) and Class I Prevention of Significant Deterioration (PSD) regulations. The objective of this study is to evaluate the SO_2 control alternatives for Colstrip Units #3 and #4.

The design and performance of the scrubbers serving Colstrip Units #1 and #2 are described in Section 2. Sulfur dioxide emission rates from Units #3 and #4 are predicted in Section 3, assuming a similar scrubber design and performance as reported for the existing units. Section 4 describes potential modifications to the planned Colstrip scrubber design expected to improve SO_2 collection efficiencies. A brief summary of alternative SO_2 control systems potentially available for Colstrip Units #3 and #4 is presented in Section 5 along with cost performance information and associated environmental and engineering sacrifices.

2.0 COLSTRIP UNITS #1 and #2 SCRUBBER DESIGN AND PERFORMANCE

An excellent description of the design and performance of the scrubbing system on Colstrip Units #1 and #2 is provided in a paper recently presented at the Fourth Symposium of Flue Gas Desulfurization. A summary of "Status and Performance of the Montana Power Company's Flue Gas Desulfurization System" by D. T. Berube and C. D. Grimm of Montana Power Company is provided in this section along with a discussion of the SO_2 collection efficiencies calculated by PES.

2.1 Scrubber Description

The flue gas cleaning system now in operation on Colstrip Units #1 and #2 consists of three scrubber modules operating in parallel per unit. Each 33 1/3% nominal scrubber module is capable of treating up to 40% of the flue gas flow for short periods of time. No scrubber bypass capability is installed. Each scrubber module consists of a variable throat venturi for particulate and sulfur dioxide removal and a spray absorption section for additional sulfur dioxide removal. This system, which was piloted for approximately one and a half years, uses the alkalinity present in the captured ash from the Rosebud seam coal for the SO_2 removal. Supplemental lime is added for pH control. The vendor for the scrubber installation was Combustion Equipment Associates. Bechtel Power Corporation was the architect-engineer for the power plants and personnel from its Research Division were involved in the devlopment of the Colstrip scrubbers. Unit #1 has been operational since September 1975 and Unit #2 since May 1976.

The design parameters of the FGD system are as follows:

1. Liquid to gas ratio: L/G 33
   split L/G 15 to venturi, L/G 18 to absorption sprays.
2. Suspended Solids in Recycle Loop: 12%.

3. Venturi Pressure Drop: 17.0 in. W. G.
4. Recycle Retention Time: 8 minutes.
5. Recycle Slurry pH: 4.5 to 5.6.
6. Particulate Emission Guarantee: Outlet grain loading not to exceed 0.018 grains per actual cubic foot as measured at the reheater outlet.
7. Sulfur Dioxide Guarantee: SO_2 emission not to exceed 1.0 lb SO_2 per million BTU heat input.
8. Closed Loop Operation: Liquid can leave the system by evaporation in the process, up through the stack, evaporation from the pond surfaces, or be purged with the sludge resulting from the scrubber operation.

The coal characteristics used in the scrubber specification are summarized below:

Coal:	Average As Received
Moisture	23.87%
Volatile Matter	28.59%
Fixed Carbon	38.96%
Ash	8.59% (Max 12.58%, Min 6.1%)
Heating Value	8500 BTU/lb (Max 8,843 BTU/lb, Min 8,162 BTU/lb)
Sulfur	.77% (Max 1.0%, Min 0.4%)

A simplified flow diagram of the Colstrip scrubber train is shown on Figure 2-1. Figure 2-2 presents a detailed view of the scrubber internals. Combustion gas exits the air heater at about 290°F, travels through a duct containing several 90° turns and enters the scrubber module. The gas then passes through the variable throat venturi where it is contacted with the slurry which flows over both the venturi bowl surface and the plumb bob. Next, it passes through the absorption zone where it is contacted with recycle liquor sprayed from the absorption nozzles. The wash tray is next in line to contact the gas. Its function is to remove entrained solids from the cleaned flue gas prior to the mist eliminators. Both the bottom of the mist eliminator and the bottom of the wash tray are sprayed continuously. The mist eliminator is sprayed with a blend of wash

COLSTRIP UNITS 1 & 2
SIMPLIFIED FLOW DIAGRAM

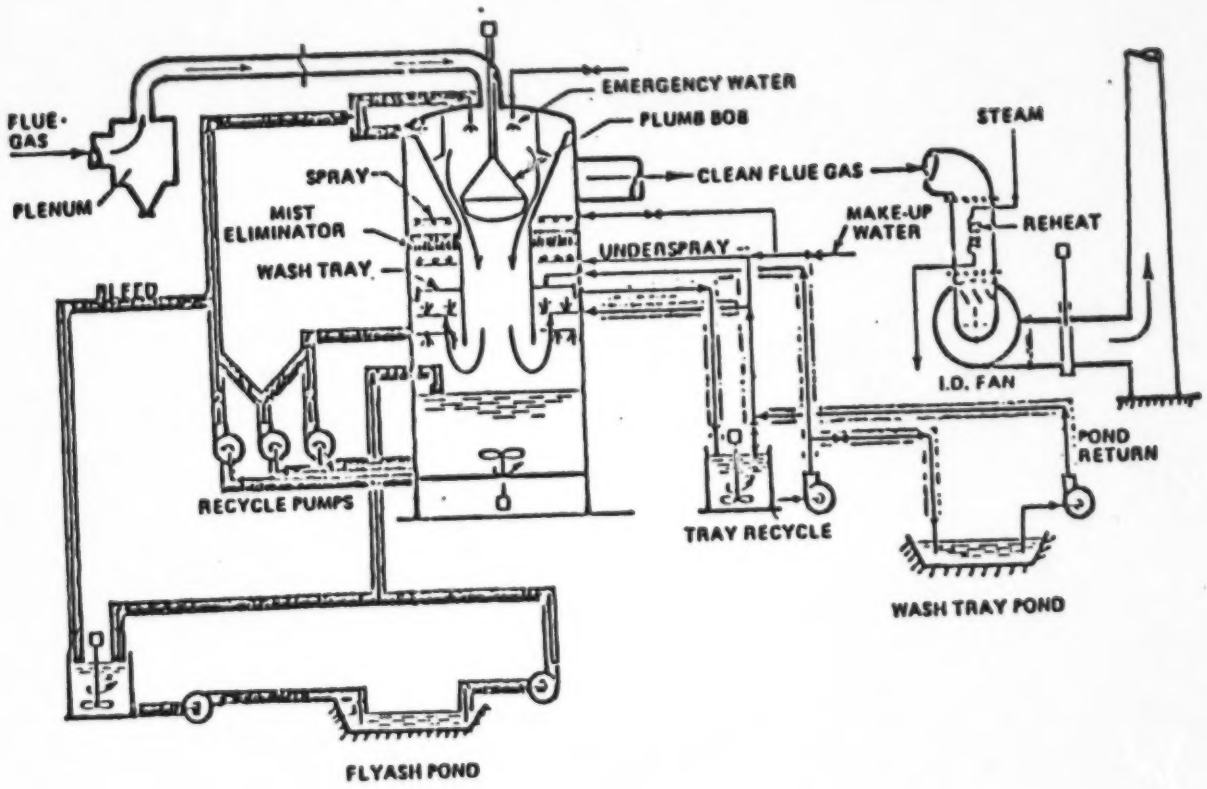

Figure 2-1

TYPICAL FGD SCRUBBER
COLSTRIP UNIT 1 & 2

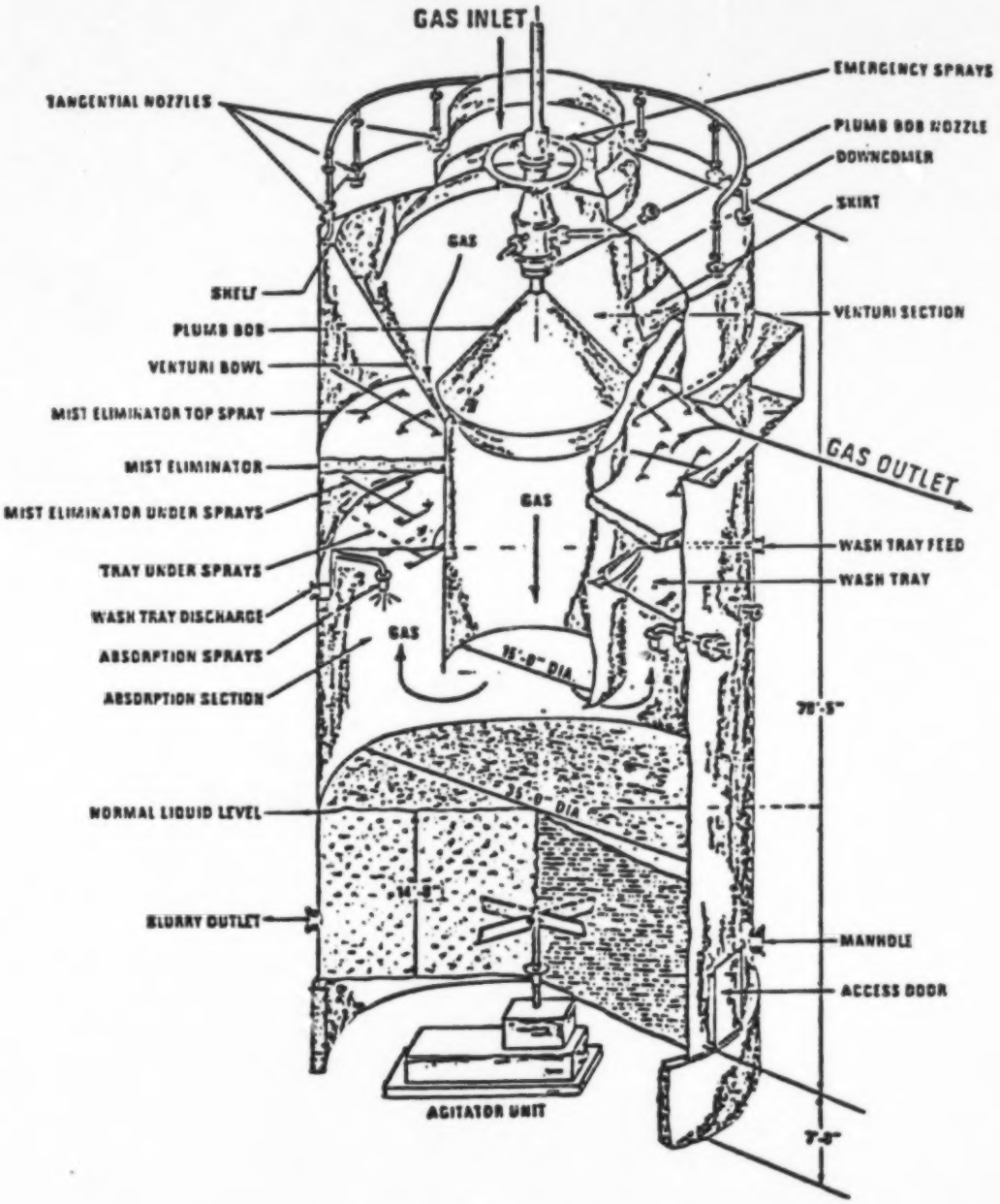

Figure 2-2

tray pond return liquid and river water. This area and the pump and agitator seals are the only places where fresh water enters the system. A liquid level is maintained on the top of the wash tray. The wash tray/mist eliminator loop works independently of the scrubber slurry recycle loop. The gas exits the scrubber module and passes through a reheat section consisting of two banks of plate-coil reheaters. The reheaters are cleaned by soot blowers placed above and between the two banks. The dry induced draft fans are last in line to contact the gas, then it passes isolation dampers and out the stack.

Two scrubber recycle pumps are needed to provide the required slurry flow to the venturi and absorption sections. The third pump is a spare that can be valved in to either the venturi or the absorption sprays. A bottom entry agitator in the main recycle tank provides necessary agitation to extract alkali values from the ash and re-suspension capability for the slurry should the module be shut down. The wash tray tank is also agitated and a set of pumps, one operating and one spare, is used in that loop. The three scrubber modules of one generating plant rely on one tray recycle tank.

Solids are bled from the scrubber recycle loop to the effluent tank, then pumped to the settling ponds immediately behind the plant. The wash tray cycle rejects its solids to a separate pond at the same location. Decanted liquid is brought back to the wash tray and scrubber recycle loops.

Materials of construction include unlined carbon steel for the scrubber inlet ducts, glass flake polyester lined carbon steel for the internal surfaces of the scrubber vessels, abrasion resistant bricks in the venturi throat, 316 stainless steel on certain areas of the plumb bob, a Norel plastic for the four pass chevron mist eliminators, 316 stainless steel in the wash tray, flakelining in the duct exiting from the scrubber through to the chimney opening,

Hastalloy G and Inconel 625 for the reheat surfaces with 316 stainless forming the duct walls around the reheater and rubber lining in the fan casing. The large recycle pumps are all rubber lined. Piping four inches and greater in diameter is rubber lined carbon steel and piping less than four inches is 316 stainless steel. The dry induced draft fan is of carbon steel construction.

The lime system consisting of storage silos for the pebble lime slakers, transfer and holding tanks, and the associated pumps and piping provides for lime slurry addition to the scrubber recycle tank for pH control.

Inlet and outlet sulfur dioxide monitors are provided on the scrubber trains. The testing station placed in the stack also is the location for the SO_2, NO_x, CO_2 and opacity monitors.

2.2 Operational History

Unit #1 has been in operation since September 1975 and Unit #2 since May 1976. The overall performance of the scrubber system has been quite good. The scrubbers have been free of massive scale formations that have been reported at other scrubber installations. The system has operated in a closed loop mode. Table 2-1 contains scrubber availability data from September 1975 through July 1977. The definition of scrubber availability below the table should be noted. The average availability for the Unit #1 scrubbers was 87% and for Unit #2 scrubbers was 91.3%. Modifications and improvements have been made in the scrubber system to correct problems and increase availability. A description of the problem areas and the solutions or corrective measures taken by MPC are provided in the following pages of this section.

Deposits occurred at the wet-dry interface located at the entrance to the scrubber modules which reduced availability to an unacceptable

Table 2-1. SCRUBBER AVAILABILITY VS PLANT LOAD

	Monthly Capacity Factor Percent		Number Days On Line		Average MW For Days On Line		Scrubber Availability Percent	
	Unit #1	Unit #2	Unit #1	Unit #2	Unit #1	Unit #2	Unit #1	Unit #2
1975								
Sep	0.5		3		50			
Oct	19.4		19		139			
Nov	42.2		24		203			
Dec	59.9		30		239			
1976								
Jan	63.8		28		265		90.0	
Feb	65.4		26		273		98.0	
Mar	57.0		24		277		97.6	
Apr	49.9		28		219		74.2	
May	26.0	1.3	14	3	210	66	96.8	100.0
Jun	0.0	23.2	0	16	0	171	-	99.7
Jul	28.0	19.5	20	13	167	180	93.2	98.7
Aug	37.8	13.0	23	10	194	162	94.7	95.8
Sep	64.5	64.6	30	30	239	232	88.6	98.3
Oct	73.1	77.0	30	31	281	298	79.9	90.3
Nov	55.6	79.7	30	30	225	303	62.7	94.1
Dec	67.2	82.3	31	31	249	297	73.8	92.5
1977								
Jan	72.9	68.2	31	30	270	258	92.5	83.4
Feb	3.0	75.3	2	27	161	285	95.4	93.8
Mar	0.0	71.3	0	28	0	293	-	96.7
Apr	49.9	68.2	25	29	236	264	83.0	84.5
May	64.1	23.3	26	13	286	209	85.4	63.0
Jun	68.6	61.4	28	28	284	249	87.4	87.8
Jul	71.8	57.5	29	28	284	238	85.1	90.6
Average							87.0	91.3

Note: Scrubber availability = total module hours available ÷ 3 (hours in month) except May through August 1976 base is days in operation because of extended scheduled outages.

degree. These are not to be confused with calcium sulfate or calcium sulfite scale formation. Gas flow tests were run on a model that duplicated the configuration of the duct from the air heater exit to the top of the scrubber module and the upper portion of the scrubber module itself. These tests found there was a maldistribution of the dust entering the scrubber module along with extreme velocity variation from one side of the duct exit to the other. In addition, a model study was made of the liquid flow on the tangential shelf above the venturi. From those studies, it was concluded that gas flow turning vanes in the duct elbow above the scrubber module and liquid guiding vanes and baffles on the tangential shelf would be required to reduce the wet-dry interface buildup. One module was modified and operation gave encouraging results. These modifications were then made during the spring and summer of 1977 to the remaining five modules and the construction time is reflected in the scrubber availability figures in Table 2-1. Actual operating experience from the modules equipped shows a significant reduction in cleaning time and has increased the time increment between inspection and cleanings.

Instrumentation in slurry and flue gas service has not been trouble free. The stack opacity, SO_2 and NO_x monitors along with the SO_2 monitors on the inlet and outlet of the scrubber modules have exhibited unstable and erratic behavior. A corrective program has shown progressive improvement in the data retrieved by these monitors during the past six months. The in line pH probes either erode away or lose sensitivity due to deposits on the elements. Slurry density monitors have given erratic and unstable operation too and a test program is in progress to isolate these devices from vibration. Both slurry density and pH, key operating parameters, are taken manually and monitored on a frequent basis.

The supplementary alkali feed system has been difficult to use due to line plugging and equipment failure. The lime system is being modified so that it will be simpler to use and less prone to plugging. Pinch valves are being placed next to the scrubber vessel on each feed line so any solid accumulation will slough off as these valves are regularly stroked. The alkaline ash captured by the scrubber has generally been adequate to keep the scrubber pH within the control range. Better control of the lime system will keep the pH more constant and allow SO_2 removal to be optimized.

Failures of the protective glass flakelining on the carbon steel vessel walls and ducts have occurred. These failures were evident prior to a major temperature excursion that occurred in Unit #1 in October 1976 but were then aggravated. The excursion followed a complete station power blackout and the failure of the emergency scrubber quench water supply system to operate. The glass flakelining along with the plastic mist eliminators were seriously damaged at that time in Unit #1 and account for low scrubber availability during November and December 1976. A failure of an ID fan motor during the same time period, independent of the temperature excursion, also contributed to the lower availability figures. If the ID fan motor was not considered in compiling the availability numbers, the scrubber availabilities would have been 88.5%, 94.0% and 81.6% for Unit #1 during the months of October, November and December 1976. Subsequent problems with other ID fan motors early in 1977 have reduced scrubber availabilities. The availability given for May 1977 for Unit #2 reflects another fan motor repair and the modifications for the wet-dry interface.

Inspection of an ID fan rotor during the spring of 1977 resulted in the finding of cracks in the center plate next to the blades. Each fan was then cleaned and critically inspected. If cracks were found or if there was a suspicion a crack might form, it was isolated and ground out. Then that portion was welded and a stiffener plate was

added. Availabilities during the summer of 1977 and the modifications carried out for the wet-dry interface show this activity.

Quick clean basket strainers were added to the suction piping of the two main recycle pumps of each vessel in place of the original start-up strainers contained in a pipe spool. This has allowed deposits and foreign materials to be removed before they clog spray nozzles and has also decreased maintenance and downtime on the vessels.

A program is under way to evaluate abrasion resistant protective lining materials that could be used where the flue gas makes its 180° turn following the venturi down-comer and passes by the absorption sprays. Impingement on the wall by the absorption spray slurry erodes the glass flakelining and this lining has been replaced at least once in each module since unit start-up.

Similarly, a program for evaluating corrosion, temperature resistant and abrasion resistant materials in other areas of the scrubber is in progress. Small test patches and full scale application of various linings are in place on several of the scrubber modules and are subject to different environments.

Plugging of the wash tray underspray nozzles on scrubber modules of both units occurred during May of 1977 and forced the plants to shut down. The major cause of the problem was traced to piping in the wash tray pond which had broken and allowed some of the pond dike material to be ingested. A parallel pipeline and pumping system was installed, the units brought on line and modification and repair made to the original piping system.

The scrubber ponds are reclaimed by a dredge system which transfers the scrubber sludge to a disposal pond approximately three miles from the plant site. Liquid from the disposal pond is returned to the scrubber ponds immediately behind the plant when the dredge is not operating. The scrubber sludge deposits in deltas in the

ponds and contain 55% - 60% solids. The material hardens very well and the dredge has had some difficulty in reslurrying the sludge. Residual alkalinity remains in the sludge deposited in these ponds and this results in the sludge taking on a cement-like nature. Improved cutters for the dredge and a delumper ahead of the dredge pump are expected to increase the solids handling capacity. More rapid filling of the wash tray pond with solids than had been expected has presented a problem in the method of removal of these materials. Each of the plant ponds has its own chemical identity due to water balance considerations. A dredge cannot be used presently to reclaim the wash tray pond volume without adversely affecting either the plant operation or the pond water balance, so a less efficient clamshell operation is now in use. Plans are being developed for the addition of another wash tray pond so that one may be dewatered and then cleaned while the other is in operation.

2.3 Scrubber Test Data And Performance

A large number of emission tests have been conducted on the Colstrip units over the 1 - 1/2 year period. EPA compliance tests for particulate, sulfur dioxide and NO_x were completed during the spring of 1977 on both plants. Also, emission monitor certification testing has been conducted following the conclusion of the NSPS emission tests. Table 2-2 shows the results of the tests. The NSPS requirements, the scrubber guarantee, the projected results from pilot plant experience and the actual tests on Units #1 and #2 are reported. The results of the operation of the full scale units agree well with the pilot plant data. The data also shows the plant emissions are well below the guarantee and the NSPS standards. Although scrubber inlet data has not been taken and efficiency per se is not available, it appears sulfur dioxide and particulate removal efficiencies predicted from the pilot plant data are being achieved.

Table 2-2. EMISSION TEST RESULTS

				SO_2			Particulate			NO_x	
				Lb/hr	Ppm	Lb/mmBTU	Lb/hr	Lb/mmBTU	% Opac	Lb/hr	Lb/mmBTU
1.	Required by NSPS (358 MW)			4,063	510	1.2	339	.10	20	2,370	.7
2.	Scrubber Guarantee (358 MW)			3,386	425	1.0	207	.06	-	2,370	.7[1]
3.	Projected from Pilot Plant (358 MW)										
	a) 0.78% S (760 PPM), 8.19% Ash			1,394	185	.41	130	.038	20	2,370	.7
	b) 1.0% S (965 PPM), 12.58% Ash			2,071	260	.61	184	.054	20	2,370	.7
4.	Unit #1 Tests:										
	Date	Gr MW	Coal As Received[4] % Sul	% Ash	Btu/lb						
	2/76	353	.83	9.03	8,638	1,587	197	.48	95.8	.029	10 [3]	954	.29
	4/76	210[6]	.71	7.79	8,861	456	87	.23	60.9	.030	12 [3]	800	.41
	7/76	184[6]	.64	8.49	8,807	258	53	.15	57.1	.031	15 [2]	740	.42
	9/76	186[6]	.62	7.93	8,633	275	56	.15	64.4	.037	11 [2]	687	.39
	12/76	223[6]	.94	8.54	8,394	898	154	.43	67.2	.032	15 [2]	662	.31
	1/77	354	.77	8.17	8,719	770 [5]	133[5]	.35 [5]	123.5	.037	13 [2]	1,459	.43
	5/77	331	.61	8.41	8,851	552	72	.16	109.6	.032	14 [2]	1,029	.29
	6/77	340[7]	.91	8.96	8,888	1,164	122	.325	89.5	.039	18.4[2]	1,296	.36
5.	Unit #2 Tests:										
	Date	Gr MW	Coal As Received[4] % Sul	% Ash	Btu/lb						
	10/76	331	.56	7.96	8,368	1,309	178	.42	88.6	.029	11 [2]	917	.30
	11/76	327	.59	7.86	8,484	696	83	.23	91.4	.029	10 [2]	993	.32
	12/76	324	.64	7.87	8,690	780	98	.25	105.7	.034	16 [2]	784	.25
	3/77	335	.63	7.96	8,739	684	84	.20	91.9	.029	8 [2]	1,399	.38
	6/77	305[8]	.72	8.48	8,929	596.5	67	.189	104.2	.051	8.4[2]	1,261.4	.403

Notes:
1. NO_x emissions guaranteed by boiler supplier equal to NSPS.
2. Average EDC monitor opacity.
3. Qualified observer, EPA Method 9.
4. Based on percent moisture of coal for period prior to test.
5. SO_2 test done at 230 MW (two scrubbers on line).
6. Two scrubber modules on line, all other tests done with three modules on line.
7. SO_2, NO_x tests 340 MW, particulate tests 260 MW.
8. SO_2, NO_x tests 305 MW, particulate tests 198.5 MW.

Table 2-2. EMISSION TEST RESULTS

	SO_2			Particulate			NO_x	
	Lb/hr	Ppm	Lb/mmBTU	Lb/hr	Lb/mmBTU	% Opac	Lb/hr	Lb/mmBTU
1. Required by NSPS (358 MW)	4,063	510	1.2	339	.10	20	2,370	.7
2. Scrubber Guarantee (358 MW)	3,386	425	1.0	207	.06	-	2,370	.7[1]
3. Projected from Pilot Plant (358 MW)								
a) 0.78% S (760 PPM), 8.19% Ash	1,394	185	.41	130	.038	20	2,370	.7
b) 1.0% S (965 PPM), 12.58% Ash	2,071	260	.61	184	.054	20	2,370	.7
4. Unit #1 Tests:								

Date	Gr MW	Coal As Received[4] % Sul	% Ash	Btu/lb									
2/76	353	.83	9.03	8,638	1,587	197	.48	95.8	.029	10 [3]	954	.29
4/76	210[6]	.71	7.79	8,861	456	87	.23	60.9	.030	12 [3]	800	.41
7/76	184[6]	.64	8.49	8,807	258	53	.15	57.1	.031	15 [2]	740	.42
9/76	186[6]	.62	7.93	8,633	275	56	.15	64.4	.037	11 [2]	687	.39
12/76	223[6]	.94	8.54	8,394	898	154	.43	67.2	.032	15 [2]	662	.31
1/77	354	.77	8.17	8,719	770 [5]	133[5]	.35 [5]	123.5	.037	13 [2]	1,459	.43
5/77	331	.61	8.41	8,851	552	72	.16	109.6	.032	14 [2]	1,029	.29
6/77	340[7]	.91	8.96	8,888	1,164	122	.325	89.5	.039	18.4[2]	1,296	.36

5. Unit #2 Tests:

Date	Gr MW	Coal As Received[4] % Sul	% Ash	Btu/lb									
10/76	331	.56	7.96	8,368	1,309	178	.42	88.6	.029	11 [2]	917	.30
11/76	327	.59	7.86	8,484	696	83	.23	91.4	.029	10 [2]	993	.32
12/76	324	.64	7.87	8,690	780	98	.25	105.7	.034	16 [2]	784	.25
3/77	335	.63	7.96	8,739	684	84	.20	91.9	.029	8 [2]	1,399	.38
6/77	305[8]	.72	8.48	8,929	596.5	67	.189	104.2	.051	8.4[2]	1,261.4	.403

Notes:
1. NO_x emissions guaranteed by boiler supplier equal to NSPS.
2. Average EDC monitor opacity.
3. Qualified observer, EPA Method 9.
4. Based on percent moisture of coal for period prior to test.
5. SO_2 test done at 230 MW (two scrubbers on line).
6. Two scrubber modules on line, all other tests done with three modules on line.
7. SO_2, NO_x tests 340 MW, particulate tests 260 MW.
8. SO_2, NO_x tests 305 MW, particulate tests 198.5 MW.

Calculations of the scrubber inlet SO_2 rate were made using the coal characteristics and plant load. From these inlet SO_2 rates an estimate was made of the SO_2 collection efficiency during each emission test. Table 2-3 summarizes these calculations. Note that it was assumed for calculation purposes that all of the sulfur in the fuel reports to the flue gas. In fact, it has been reported in the literature that from 5 to 20% of the sulfur in the Western coals is contained in ash. Of the sulfur contained in the coal an average of 83.5% was removed according to the 13 emission tests. For Units #1 and #2 the first emission test indicates significantly lower SO_2 control efficiencies than subsequent tests. If these two tests are excluded the average SO_2 control efficiency is 85.6%. All but the initial Unit #1 and #2 tests indicate SO_2 removal efficiencies of greater than 80%.

2.4 Scrubber Costs

Actual construction costs for Colstrip Units #1 and #2 with some portion estimated through June 1977 are listed in Table 2-4. The emission control system alone costs $63.98 per net kW. When the scrubber sludge disposal system is added, the cost rises to $83.74 per net kW. The bottom ash and other disposal ponds are not included in these costs. Work is still proceeding on the installation and these costs will increase. These costs describe a combined particulate-sulfur dioxide removal system requiring minimal chemical addition, installed as a new unit and ordered in 1972.

It was reported by MPC that the first cost (capital cost) of the scrubbers for the first two Colstrip units was approximately 30% of the entire plant first cost.

Table 2-3. COLSTRIP SO_2 CONTROL SYSTEM PERFORMANCE

Date	MW	%S	Btu/lb	Lb SO_2/Hr* In	Lb SO_2/Hr Out	SO_2 Removal Efficiency	
Unit 1							
2/76	353	0.83	8,638	6,416	1,587	75.3	
4/76	210**	0.71	8,861	3,183	456	85.7	
7/76	184**	0.64	8,807	2,529	258	89.8	
9/76	186**	0.62	8,633	2,527	275	89.1	
12/76	223**	0.94	8,394	4,724	898	81.0	84.7% Average
1/77	354	0.77	8,719	5,914	770	87.0	
5/77	331	0.61	8,851	4,315	552	87.2	
6/77	340	0.91	8,888	6,585	1,164	82.3	
Unit 2							
10/76	331	0.56	8,368	4,190	1,309	68.8	
11/76	327	0.59	8,484	4,302	696	83.8	
12/76	324	0.64	8,690	4,514	780	82.7	81.6% Average
3/77	335	0.63	8,739	4,568	664	85.5	
6/77	305	0.72	8,929	4,652	596.5	87.2	
					(Average	83.5%)	

* Calculated by PES assuming all fuel sulfur reports as SO_2 in the flue gas to scrubbers.

** Two scrubber modules operating.

Coal data were adjusted by MPC to "as received basis."

Table 2-4. FGD SYSTEM COSTS - TWO GENERATING UNITS

		Dollars	$/Net kW*
1.	Scrubber subcontract and out of scope additions by prime contractor (includes foundation, field wiring, insulation, heat tracing, painting, piping to ponds, piping between modules and field distributables in addition to the scrubber modules, ductwork, equipment supply and erection)	$33,677,261	$51.02
2.	Owners' cost including interest at $2,792,000	4,374,000	6.62
3.	Subtotal as of December 1976	38,051,261	57.65
4.	Estimated cost for work in progress (cost responsibility under dispute)	4,178,499	6.33
5.	Fly ash ponds (temporary storage), fly ash slurry transport system and evaporation pond	12,722,131	19.29
6.	Incremental costs (auxiliary boiler, FD fans, start-up and auxiliary transformer)	317,520	0.48
7.	TOTAL**	$55,269,411	$83.74

*This cost does not include an additional claim submitted by the subcontractor. It also does not include a value for reduced plant capacity, although for many purposes, it should.

**Net rating 330 MW/unit; gross rating 358.4 MW/unit.

3.0 PLANNED SCRUBBER SYSTEM FOR COLSTRIP UNITS #3 AND #4

Information and data regarding the planned scrubber system for Colstrip Units #3 and #4 were obtained at meetings and during discussions with D. T. Berube and C. D. Grimm of Montana Power Company.

3.1 Scrubber Description

Montana Power Company has indicated that the scrubber system design planned for Colstrip Units #3 and #4 will make use of identical scrubber modules as are installed on the first two units. MPC feels that Colstrip Units #1 and #2 have demonstrated successful development of a scrubber system suited for the particular characteristics of Colstrip coal, achieving low emissions, zero water discharge and efficient use of resources such as chemicals, water, land and money. No other power plant equipped with scrubbers is operating with per unit emissions less than Colstrip in a closed loop mode. The high scrubber availability and SO_2 control efficiency described in Section 2.3 are cited as factors in deciding to utilize a similar scrubber design for Colstrip Units #3 and #4.

It is planned to install eight scrubber (seven plus one spare) modules on each of the new Colstrip units. The improvements and field modifications developed during the first years of operating the existing Colstrip Units #1 and #2 scrubbers are expected to be incorporated into the planned scrubbers. Improved scrubber availability is anticipated due to these design changes, as well as the use of a spare scrubber module per unit. For a description of the scrubber module design and system improvements the reader should review Sections 2.1 and 2.2.

3.2 Emission Estimates

Estimates of the SO_2 emissions for worst case and an average or typical case are presented in this section, assuming various SO_2 removal efficiencies. Throughout the calculations all of the sulfur contained in the fuel is assumed to appear as SO_2 in the flue gas. The SO_2 control efficiencies discussed are therefore system control efficiencies rather than actual scrubber SO_2 removal efficiencies.

Coal is a heterogeneous material containing organic combustible matter and mineral matter. Sulfur exists in coal in two principal forms; organic and inorganic. Organic sulfur is chemically bound to the coal and cannot be removed by physical or mechanical processes. On the other hand, inorganic sulfur (pyritic sulfur) is not bound chemically and may be physically removed to varying degrees from the coal. The coal at Colstrip is pulverized and partially dried before firing. A portion of the pyrites (and pyritic sulfur) are removed from the coal during the coal preparation and not combusted. Also a portion of the sulfur in combusted coal is retained in the ash after combustion. From 5 to 40% of the sulfur may be retained in the ash for Western coals. As a result of these factors (the removal of a portion of the pyritic sulfur prior to combustion and the retention of a portion of the combusted coal sulfur in the ash) the sulfur dioxide load at the inlet of the scrubbers is not twice (2 lb SO_2 / 1 lb S in coal) the sulfur content of the "as received" coal. The percent or amount of pyritic sulfur removed and sulfur retained in ash are not known for Colstrip. For this reason an SO_2 removal or control efficiency for the system has been used rather than a control efficiency for the scrubbers. No adjustments were made to account for removal of pyritic sulfur and sulfur retention in the ash. All calculations were performed for and all results are reported for each individual unit. Since Colstrip Units #3 and #4 are identical in size and design the

total emission rate for the combined units would be twice the values cited in the remainder of this chapter.

3.2.1 Worst Case Emission Rates

A sulfur content of 1.0% and heating value of 8,162 Btu/lb along with a plant load of 100% (7,573 x 10^6 Btu/hr heat input) were assumed as representative of worst case conditions. Worst case conditions, by definition, mean the conditions resulting in the maximum SO_2 emission rate. These worst case conditions represent a rare or unlikely short-term event. An uncontrolled SO_2 emission rate (from each unit) of 18,557 lb/hr (222.7 TPD) was calculated. With an SO_2 control efficiency of 73.7% (the removal efficiency projected under worst coal conditions by MPC from the pilot plant data for Colstrip Units #1 and #2) a per unit SO_2 emission rate of 4,880 lb/hr or 58.6 TPD is predicted. Four other SO_2 control efficiencies were used in the SO_2 emission rate projections.

A control efficiency of 80% was selected as representative of a value achieved or surpassed in all but the first weeks of scrubber operation on Units #1 and #2. The average SO_2 control efficiency, measured to date for Units #1 and #2, of 83.5% (see Table 2-3) was used to compute SO_2 emission rates. Control efficiencies of 85 and 90% were also used. The 90% value represents the approximate limit of proven scrubber technology. The SO_2 emission rates calculated for the worst case conditions assuming the various control efficiencies are presented in a variety of units in Table 3-1.

3.2.2 Typical Emission Rates

A sulfur content of 0.77% and a heating value of 8,500 Btu/lb with a 70% plant load (5,301 x 10^6 Btu/hr heat input) were selected as representative of typical or average conditions. Typical or average conditions, and the predicted SO_2 emission rates, are useful for

long-term impact assessments. An uncontrolled SO_2 emission rate (per unit) of 9,604 lb/hr (115.3 TPD) was computed. The SO_2 emission rates resulting from application of the various levels of SO_2 control are provided in Table 3-2.

Table 3-1. WORST CASE EMISSION RATES

(1.0% S 8,162 Btu/lb 100% Plant Load)

SO_2 Control Efficiency	SO_2 Emission Rate			
	lb/hr	TPD	$lb/10^6$ Btu	g/sec
Uncontrolled	18,557	222.7	2.45	2,343
73.7%	4,880	58.6	.64	615
80 %	3,711	44.5	.49	468
83.5%	3,062	36.7	.40	386
85 %	2,784	33.4	.37	351
90 %	1,856	22.3	.25	234

Table 3-2. TYPICAL EMISSION RATES

(.77% S 8,500 Btu/lb 70% Plant Load)

SO_2 Control Efficiency	SO_2 Emission Rate			
	lb/hr	TPD	$lb/10^6$ Btu	g/sec
Uncontrolled	9,604	115.3	1.81	1,211
73.7%	2,526	30.3	.48	319
80 %	1,921	23.1	.36	242
83.5%	1,585	19.0	.30	200
85 %	1,441	17.3	.27	182
90 %	960	11.5	.18	121

3.3 Scrubber Costs

The cost data reported by MPC for the scrubber system installed on Colstrip Units #1 and #2 were escalated and adjusted to reflect the larger unit size and later installation date. Start-up dates in 1981 and 1982 were projected for Units #3 and #4, respectively. It was assumed that the $83.74 per net kW value reported for Units #1 and #2 (see Section 2.4) was in terms of 1977 dollars. Assuming an escalation rate of 7% per year over the 4 years, a cost of $109.77 per net kW is estimated. The total cost of the scrubber system for Units #3 and #4 is computed as $153,678,000.

In a memo to Walter C. Barber, Director of EPA's Office of Air Quality Planning and Standards dated June 10, 1977, MPC provided a cost estimate for the scrubbers at Colstrip Units #3 and #4. Starting with a $80/kW figure for Colstrip Units #1 and #2, and escalating at 8% per year to 1981 (6 years) gives 80 x 1.59 or $127.2/kW. To account for the additional redundancy (a spare scrubber) required on Units #3 and #4 a factor of 8/7 was applied raising the scrubber system cost to $145.4/kW. A total cost for the Units #3 and #4 scrubber system is therefore $203,560,000. MPC also performed an Order of Magnitude gross cost estimate based on Colstrip Units #1 and #2 plant costs, with a percentage allocation for the scrubbers. These computations project a total scrubber system cost of in the range of $180 - $200 million. Stated another way, the scrubber system cost for Units #3 and #4 is estimated to be about $128 to $142/kW.

4.0 MODIFICATION OF PLANNED SCRUBBERS

Modifications or improvements in the planned Colstrip Units #3 and #4 scrubber system design with the objective of increasing the SO_2 control efficiency might be possible, but several interrelated factors must be considered. Field modifications, which have lowered scrubber maintenance requirements and increased scrubber reliability or availability, have been made on the Colstrip Units #1 and #2 scrubbers. The objective of these improvements has not been to increase SO_2 control efficiency, per se. Since no scrubber bypass capability was provided for at Colstrip Units #1 and #2, the relation between increased scrubber reliability and annual SO_2 emissions would be difficult to quantify. When adequate scrubbing capacity is not available to handle Unit #1 or #2 flue gases, the boiler(s) must be operated at a reduced load(s) or shut-down. The planned scrubber system for Colstrip Units #3 and #4 will utilize eight scrubbers per unit (seven operating and a spare) to minimize the occurrence of scrubber caused reductions in plant load.

A list of factors to be considered or evaluated before adopting any design modification includes:

- water usage and balance
- waste disposal - quantity and characteristics
- chemical consumption
- reliability
- energy requirements
- maintenance requirements
- operating experience

The evaluation of the impacts on these factors of scrubber design modifications to improve SO_2 removal could necessitate a pilot program. In this section, potential scrubber modifications aimed

at improved SO_2 control efficiency are identified. A comprehensive evaluation of the impacts on the factors listed above could not be performed within the scope of this study. Potential impacts have been identified and are noted briefly.

4.1 Increased L/G Ratio or Additional Sprays

The redesign of the scrubbers to operate at a higher L/G ratio or with additional sprays is a potential method of improving SO_2 removal efficiency. The relationship between the L/G ratio and SO_2 control efficiency $\left(\eta_{SO_2}\right)$ is not known precisely, but generally, as L/G is increased η_{SO_2} also increases. Several methods of increasing the L/G ratio are possible. Increasing the liquid pumping rate and amount of spray per nozzle is one option. Increased pumping costs (larger pumps and more energy consumption) as well as more rapid nozzle wear and more frequent shut-down for nozzle replacement would be expected. A second, and possible better method of raising the L/G ratio, is to increase the number of absorption sprays while maintaining the rate of spray from each nozzle. The placement of the additional sprays within the scrubber vessel could affect the SO_2 control efficiency and other scrubber system parameters. The most significant increase in SO_2 control efficiency might be achieved by incorporating an additional absorption spray section operated on a separate water loop. The operation of a separate water loop would be required if a two-stage absorption system was needed. The scrubber system design modifications to achieve a second SO_2 absorption stage would be significant and worthy of pilot plant testing.

The incorporation of an increased L/G ratio or additional sprays would affect the scrubber system design and operation. Extensive scrubber vessel arrangement and size modifications, such as

increasing the scrubber height and/or diameter to maintain sufficient slurry recycle retention time. Larger pumps would be required with an increased L/G ratio, and if a separate, additional spray section were incorporated, additional pumps, nozzles and piping would be required. The increased L/G ratio would impact the water balance. Water consumption would be higher and it is uncertain if a closed loop water balance could be maintained. These modifications might also adversely affect the scrubber system reliability. Maintenance requirements would be increased due to the additional sprays and pumps or nozzle wear. Energy consumption would increase due to the higher liquid pumping requirements. As with all modifications resulting in a higher SO_2 removal efficiency, the quantity of solid wastes to be disposed of would increase. Handling and disposal of greater quantities of scrubber sludge or wastes would add to the capital and operating costs.

4.2 Increased Lime Addition

A design concept used in the Colstrip Units #1 and #2 scrubbers is the utilization of the alkalinity of the fly-ash for SO_2 removal. Lime is added to the existing scrubbers for pH control and not for SO_2 absorption purposes. The use of additional lime as a method of increasing the SO_2 removal efficiency could be considered an alternative scrubbing technique rather than a modification to the planned scrubber system. The amount and role played by the lime in the scrubbers would determine whether increased lime addition were a modification or an alternative SO_2 control method. For the case where lime is added to enhance SO_2 absorption while relying primarily on the fly-ash alkalinity, a discussion of the impacts of increased lime addition on other scrubber system parameters is appropriate in this section.

The redesign to allow for the use of additional lime could result in several adverse scrubber system impacts. The scrubber chemistry, recognized as very complex, could be altered significantly and would require pilot plant investigation. Changes in the scrubber chemistry could affect the slurry recycle retention time. Scrubber vessel size and arrangement modifications might be required to provide adequate retention time. Scrubber scaling problems might become a significant problem and result in higher maintenance requirements and decreased scrubber availability. If hard deposits or scaling resulted, difficult operating and maintenance problems would have to be overcome. Metals in the captured fly-ash are thought to act as a catalyst, aiding in the oxidation of SO_2 to SO_4. Calcium sulfate ($CaSO_4$), a scrubber product, is more readily decanted and forms a more stable disposal material. If increased lime addition altered the scrubber chemistry and resulted in greater sulfite formation, the system design would require several modifications. More difficult water separation and increased disposal problems would result.

The increased usage of lime would increase chemical consumption and costs. Lime handling and storage facilities would have to be enlarged and capital costs and operating expenses would rise. The handling of larger quantities of lime would result in greater energy consumption. Lime is obtained from limestone which must be mined and processed.

The impact of increased lime addition on water usage and the water balance is uncertain. The ability to maintain a closed loop water balance would have to be tested.

The higher SO_2 collection efficiency combined with greater lime usage would result in larger quantities of scrubber sludge for disposal. As a result, waste handling and disposal requirements and costs would increase. The dewatering and disposability of the

scrubber waste might also be affected. A less stable scrubber waste product would raise disposal costs and/or result in greater potential environmental impacts.

4.3 Pilot Plant Program

Any substantial change in the scrubber system design would require a pilot plant program to verify process parameters, performance and to evaluate the impacts on all related factors. Reliability and operating experience are considered essential by MPC before committing to a modified scrubber system design. According to MPC, nine months to two years would be required to verify and evaluate scrubber design modifications. The cost of delaying Colstrip Units #3 and #4 and the impact of delays on the needs of MPC customers could be significant. Any scrubber system changes which sacrificed the closed loop water balance or reliability; or caused increased consumption of energy, chemicals, water or land for disposal, would require comprehensive evaluation.

5.0 ALTERNATIVE SO_2 CONTROL SYSTEMS

Several factors must be considered before selecting an SO_2 control system. A scrubber system cannot be selected solely on the basis of SO_2 removal efficiency. Likewise, the performance of a scrubbing system cannot be summarized and reported entirely in terms of SO_2 removal efficiency. Governing air quality standards and emission regulations generally establish the required level of SO_2 control system operation. An emission limitation for a given power plant is typically determined by air quality or dispersion modeling which utilizes site specific meteorological, plant and emission data. Once an emission limit is established based on the applicable emission regulations and air quality impact constraints, the optimum SO_2 control system can be selected after consideration and evaluation of the following factors:

governing water quality standards and effluent limitations

fuel characteristics and composition

water requirements - quality and quantity needed

chemical consumption and availability

particulate removal equipment requirements

quantity and characteristics of wastes to be disposed of

energy consumption

maintenance requirements

auxiliary facilities required

reliability

operating experience

capital and operating costs

The fuel characteristics and composition can be used to calculate the overall SO_2 control efficiency required to achieve the required emission limitation. The availability of water plays an important role in scrubber system design. Suitable space and waste disposal facilities are also needed.

Favorable reliability and operating experience are demanded of all commercial control systems. The best SO_2 control system must be determined for each specific power plant in accordance with available conditions and resources. The constraints or factors listed above can vary widely between plants, limiting the applicability of an SO_2 control system. This chapter describes the Colstrip Units #3 and #4 SO_2 control system requirements and discusses the availability of alternative SO_2 control systems. Information regarding flue gas desulfurization (FGD) systems operating at other domestic power plants and potentially usable at Colstrip are summarized. Well over 50 FGD processes have been invented; many have undergone testing in laboratory or pilot plant operations. Relatively few have been operated on full-scale utility boilers. A tremendous volume of material has appeared in the literature regarding FGD systems. This is a reflection of the large number of FGD processes tested and the controversy between industry and the environmental community. Only a cursory review of alternative FGD systems could be performed within the scope of this study.

5.1 Colstrip SO_2 Control System Constraints

In addition to the SO_2 emission limitation required to meet the Class I PSD increment, other important site specific parameters must be incorporated into the design of the Colstrip SO_2 control system. Due to the scarcity of water in the Colstrip area and water pollution effluent limitations, a closed loop water balance

with minimum water consumption is called for. The coal characteristics of low-sulfur content and high fly-ash alkalinity also influence the scrubber system design. The utilization of the fly-ash alkalinity for SO_2 absorption, rather than a chemical brought from offsite is desirable. The availability of solid waste disposal sites and difficulties in obtaining a marketable byproduct from low sulfur coal flue gases limit consideration to only nonregenerable FGD processes. Since a readily disposable scrubber waste is desired a process yielding an easily dewatered and stable waste product is advantageous.

5.2 Operational FGD Systems

The review of alternative SO_2 control methods was limited to FGD systems which have been installed and operated on domestic power plants. The summary of FGD system operating experience provided in the Summary Report - Flue Gas Desulfurization Systems - August - September 1977 indicates that there are currently 29 operating FGD systems in the United States. Of these 29 FGD systems, 12 are operated on plants burning coal with a sulfur content of 1.0 percent or less, similar to Colstrip. A summary of these operational low-sulfur coal FGD systems is presented in Table 5-1. The 12 systems can be classified into four FGD processes as follows:

FGD Process	Number of Units	Capacity MW	Number of years Experience
Limestone scrubbing	5	1,910	81
Sodium carbonate scrubbing	3	375	96
Lime scrubbing	2	240	119
Alkaline fly-ash scrubbing	2	720	37
TOTAL	12	3,245	333

Table 5-1. SUMMARY OF LOW SULFUR COAL OPERATIONAL FGD SYSTEMS AS OF SEPTEMBER 1977

Utility Company Power Station	New Or Retrofit	Size Of FGD Unit (MW)	Process / Vendor	Coal Characteristics (Percent Sulfur)	Start-Up (Month/Year)	Experience (Months)
Arizona Public Service Cholla No. 1	R	115	Research Cottrell Limestone Scrubbing	.44 - 1.	10/73	47
Kansas City Power And Light Hawthorn No. 3	R	140	Combustion Engineering Lime Scrubbing	.5 - 3.5 *	11/72	58
Kansas City Power And Light Hawthorn No. 4	R	100	Combustion Engineering Lime Scrubbing	.5 - 3.5 *	8/72	61
Kansas Power And Light Lawrence No. 4	R	125	Combustion Engineering Limestone Scrubbing	.5	1/77	9
Montana Power Company Colstrip No. 1	N	360	ADL / Combustion Equipment Associate Alkaline Fly-Ash Scrubbing	.8	10/75	23
Montana Power Company Colstrip No. 2	N	360	ADL / Combustion Equipment Associate Alkaline Fly-Ash Scrubbing	.8	7/76	14
Nevada Power Company Reid Gardner No. 1	R	125	ADL / Combustion Equipment Associate Sodium Carbonate Scrubbing	.5 - 1.	4/74	41
Nevada Power Company Reid Gardner No. 2	R	125	ADL / Combustion Equipment Associate Sodium Carbonate Scrubbing	.5 - 1.	4/74	41
Nevada Power Company Reid Gardner No. 3	N	125	ADL / Combustion Equipment Associate Sodium Carbonate Scrubbing	.5 - 1.	7/76	14
Northern States Power Company Sherburne County Station No. 1	N	710	Combustion Engineering Limestone Scrubbing	.8	3/76	18
Northern States Power Company Sherburne County Station No. 2	N	680	Combustion Engineering Limestone Scrubbing	.8	4/77	5
South Carolina Public Service Winyah No. 2	N	280	Babcock And Wilcox Limestone Scrubbing	1.	7/77	2

Note: * Two grades of coal are burned; a low sulfur coal with typical sulfur content of .5% and a high sulfur coal with a typical sulfur content of 3.5%. The FGD system was converted to a tail-end wet lime scrubber system in early 1977.

The two alkaline fly-ash scrubbing systems are Colstrip Units #1 and #2 which were described in Section 2. The three other FGD processes operated at plants burning low-sulfur coal are described in the following subsections.

5.2.1 Limestone Scrubbing Systems

Five limestone scrubbing systems are operating on power plants burning low-sulfur coal. At the Cholla #1 unit (115 MW) operated by Arizona Public Service a Research Cottrell limestone scrubbing system has been operated since October 1973. The average coal characteristics are 0.52% sulfur, 10,150 BTU/lb heat content and 13.5% ash. Two parallel trains (Modules A and B), each designed to handle 50% of the boiler's flue gas load, are designed to have a combined SO_2 removal efficiency of 58.5%. Either one or both of the scrubbers can be bypassed. The A-side consists of a variable throat flooded disk scrubber followed by a packed tower. The A-side SO_2 removal is reported to be about 90%. The B-side is similar in design except that the tower is not packed and limestone slurry is not circulated through it. The B-side has a low degree of SO_2 removal (25%). The open loop water system uses 1.04 GPM/MW. The unstabilized scrubber sludge is disposed of in unlined solar evaporation ponds. No pond water is recycled to the FGD system. Corrosion, erosion, scaling and plugging problems have been encountered with the scrubber system. Scrubber availability has been about 90%. No SO_2 removal efficiency or emission rate data were available to verify the design efficiency of 58.5%.

A new limestone Combustion Engineering scrubbing system has replaced a previously operated limestone injection FGD system at the Kansas Power and Light Lawrence #4 unit. The new FGD system which commenced operations in January 1977 consists of a rod scrubber followed by a spray tower for SO_2 absorption. The rod scrubber, designed to remove particulates, is fed overflow from the spray

tower recirculation tank and a significant portion of SO_2 is removed also. The plant can burn either natural gas or coal. Continuous SO_2 monitors have recorded SO_2 removal efficiencies of better than 85%. Limited scrubber operating experience is available as the plant has operated on coal only about 10 days to date.

Combustion Engineering also designed the limestone scrubbing systems operated on Northern States Power Company's Sherburne County Stations #1 and #2. Colstrip coal is burned in both units. Simultaneous particulate and SO_2 removal are achieved in the scrubber system. At each unit 12 scrubbing modules, 11 of which are required for full load capacity, are operated. The scrubbing system is comprised of a first stage fixed-rod venturi scrubber for particulate removal and a marble bed absorber to complete particulate removal and achieve the necessary SO_2 removal. The design SO_2 control efficiency is based upon the removal of 50% of the sulfur in the fuel (maximum fuel sulfur content of 1.2%) or a 200 ppm SO_2 emission concentration, whichever outlet value is greater. The scrubbing systems at Sherburne County Stations #1 and #2 both operate with an open loop water system with a water consumption rate of 1.13 GPM/MW. Unstabilized sludge is disposed in lined ponds. Water from the ponds is recycled back to the process. Unit #1 (710 MW) has been in operation since March 1976 and Unit #2 (680 MW) began operation in April 1977. The availability of the scrubber systems have been about 90%.

The South Carolina Public Service Winyah No. 2 plant (280 MW) recently began operation. A Babcock & Wilcox designed limestone scrubbing system is installed. Medium sulfur Virginia coal with a maximum 1.9% sulfur and a 11,200 BTU/lb heat content is burned. An ESP to remove 99% of the inlet fly-ash is installed ahead of the scrubber. The scrubber is designed to remove 69% of the SO_2

from 50% of the flue gas. The remaining half of the boiler flue gas is bypassed around the FGD system and recombined with the scrubbed portion for reheat purposes. The FGD system consists of one scrubber-absorber train, including a venturi scrubber and a tray tower absorber. The overall SO_2 removal efficiency is 25% (935 ppm inlet and 294 ppm outlet). The water system is open-loop and the scrubbing wastes are discharged to an unlined pond. No availability or operating experience data are provided yet.

5.2.2 Sodium Carbonate Scrubbing

Nevada Power operates the Reid Gardner Station consisting of three (125 MW) units burning coal with from 0.5 to 1.0% sulfur and a heat content of 12,450 BTU/lb. Units #1 and #2 were retrofitted with sodium carbonate scrubber systems. Unit #3 is a new installation also equipped with a sodium carbonate based FGD system. Combustion Equipment Associates in association with A. D. Little designed and installed the FGD systems. Each unit is equipped with a single FGD module consisting of a twin variable-throat venturi scrubber, followed by a single-stage wash tray. Bypassing of the module is possible. Primary particulate removal is accomplished by mechanical collectors (75% efficient) installed upstream of the scrubber. A common facility for sodium carbonate ore (trona) storage and processing serves all three FGD systems. A sulfur dioxide removal efficiency of 85% is reported. There are two sources of liquid effluent from the scrubbers; a slip stream discharged from the recirculation tank and the underflow from the clarifier. The FGD system operates on an open water loop with no liquid recycled to the modules from the ponds. A water consumption rate of 1.52 GPM/MW is reported. Unstabilized sludge is disposed in solar evaporation ponds. Plugging problems in several areas of the scrubber systems have been encountered. Scrubber reliability has been about 80%

for Units #1 and #2 and 60% for Unit #3.

5.2.3 Lime Scrubbing

The only lime scrubbing FGD process operating on low sulfur coal flue gases is installed at the Kansas City Power and Light Hawthorn Units #3 and #4. Both units are designed to burn either (1) a low sulfur Wyoming coal typically containing 0.5% sulfur and having a heat content of 9,800 BTU/lb; or (2) a high sulfur Oklahoma coal with 3.5% (average) sulfur and 11,500 BTU/lb heat content. The original FGD system consisted of limestone injection and Combustion Engineering designed scrubbers. Dry limestone was injected directly into the furnace box and calcined to lime. The furnace calcined lime and boiler flue gas were then discharged to a tail-end wet scrubbing system consisting of two marble-bed absorbers where particulates and SO_2 were removed. The spent lime and other scrubbing wastes were then discharged into a common clarifier tank and the underflow was pumped, untreated and unstabilized, to an unlined disposal pond. Boiler tube plugging problems attributed to the limestone injection forced changes in the mode of operation. The scrubbing system was modified in early 1977 and now operates as a tail-end wet lime scrubbing system. Two marble-bed scrubbers are installed on each boiler. The fresh water make-up requirement is approximately 7.0 GPM/MW to maintain the open loop water balance. The SO_2 removal efficiency is estimated at 50 to 60% for both modules although no tests have been run.

5.2.4 Summary of Performance

A summary is presented in Table 5-2 of important design and performance parameters for the FGD systems operated at power plants burning low-sulfur coal. Only Colstrip Units #1 and #2 currently operate on a closed loop water balance. The scrubber availability and SO_2 removal efficiency of the Colstrip FGD system are comparable or better than the other low sulfur coal FGD systems. Comparing the Colstrip Units #1 and #2 performance data with other FGD systems reported in the Summary Report - Flue Gas Desulfurization Systems August-September, 1977, it appears that lower SO_2 emissions, in terms of $lb/10^6$ BTU or ppm, are achieved at Colstrip than with other scrubber systems. Sulfur dioxide removal efficiencies of 90% or greater reported in the Summary Report and elsewhere in the literature are for plants burning high sulfur coal. The $lb/10^6$ BTU, ppm or TPD SO_2 emissions at these plants would exceed the emission level achieved at Colstrip. It must be pointed out that the FGD systems included in Table 5-2 were not designed solely for maximum SO_2 removal efficiency; but, as in the Colstrip design, site specific criteria or restraints were incorporated into the individual system designs.

FGD System	SO_2 Removal Efficiency	Water Balance	Water Usage GPM/M	Availability
Limestone				
Cholla #1	58.5%	open loop	1.04	90%
Lawrence #4	85%	open loop	?	?
Sherburne #1 and #2	50% (or 200 ppm)	open loop	1.13	90%
Winyah #2	69% from 1/2 of flue gas (25% overall)	open loop	?	?
Lime				
Hawthorn #3 & #4	50 to 60%	open loop	7.0	?

Table 5-2. FGD SYSTEM PERFORMANCE SUMMARY (Continued)

FGD System	SO_2 Removal Efficiency	Water Balance	Water Usage GPM/MW	Availability
Sodium Carbonate				
Reid Gardner #1, 2, and 3	85%	open loop	1.52	60 to 80%
Alkaline Fly-ash				
Colstrip #1 and #2	73.7% guarantee (83.5% actual)	closed loop	?	90%

5.3 FGD System Economics

The costs of an SO_2 control system consist of the capital costs of purchasing and installing the system and the annual costs of ownership, operation and maintenance of the system. Capital costs can be further categorized as direct and indirect costs. Direct costs are defined as those for purchase of the items of equipment and the labor and material required to install and interconnect the equipment. Indirect costs are those not attributed to specific equipment items such as freight, interest, taxes, spare parts, engineering, overhead, shakedown, and contingencies. Annual costs are categorized as operation and maintenance costs and fixed costs. Operation and maintenance costs include those expenditures for raw materials, utilities, direct labor, maintenance, and supervision. Fixed costs include depreciation, taxes, insurance, and costs of borrowed capital.

Scrubber system costs are generally reported in $/kW for capital costs and mills/kWh for operating costs. Before attempting to compare the costs from one plant or system to another one should determine what has been included or excluded from the figures and the base year for costs are reported. Appendix A of the Summary Report

Flue Gas Desulfurization Systems August-September 1977 contains cost data for 47 FGD systems. Capital costs range from less than $10/kW to $189/kW. Operating costs range from about .25 mills/kWh to over 17 mills/kWh.

Differences in the reported cost data caused by including or excluding the costs of particulate removal, sludge disposal, lime or limestone preparation, indirect costs and other items make comparison FGD system economics difficult and inconclusive without further information. Insufficient data were available at this time to compare the costs of the alternative SO_2 control systems for Colstrip.

6.0 SUMMARY

A review of the design, performance and operating experience at Colstrip Units #1 and #2 and other FGD systems operating on domestic power plants burning low-sulfur coal was performed. According to the results of 13 emission tests at Colstrip Units #1 and #2 the scrubbers have consistently reduced SO_2 emissions to less than 0.5 $lb/10^6$ BTU. The average SO_2 emission rate is 0.274 $lb/10^6$ BTU and the average SO_2 removal efficiency is 83.5%. A scrubber system availability of approximately 90% has been maintained. This scrubber performance, combined with other important system design features (such as a closed loop water balance and use of alkaline fly-ash rather than purchased lime or limestone for SO_2 absorption) make the planned scrubber system design optimum for the Colstrip site.

The SO_2 emissions for Colstrip Units #3 and #4 were predicted assuming various levels of SO_2 removal. The expected performance of the planned alkaline fly-ash scrubbing system for Units #3 and #4 was described. Available scrubber cost information and estimates for Colstrip were reported. Potential modifications to improve SO_2 removal capabilities were discussed. A summary was presented of FGD systems operating on domestic power plants burning low sulfur coal.